State of Utah

Department of Environmental Quality

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Site ID: 10355

# Title V Operating Permit

**PERMIT NUMBER: 3500068002(DRAFT)**
**DATE OF PERMIT: (Assigned in Final Permit)**
Date of Last Revision: (Assigned in Final Permit)

This Operating Permit is issued to, and applies to the following:

| **Name of Permittee:** | **Permitted Location:** |
|---|---|
| PacifiCorp<br>1407 W. North Temple<br>Salt Lake City, UT 84116 | Gadsby Power Plant<br>1407 West North Temple (rear)<br>Salt Lake City, UT 84116 |

UTM coordinates: 4,513,250 meters Northing, 421,650 meters Easting
SIC code: 4911

## ABSTRACT

The PacifiCorp Gadsby Power Plant is a natural gas-fired electric generating plant consisting of three steam boilers (Units #1, #2, and #3) and three combustion gas turbines (Units #4, 5, and #6). Unit #1 is a 65 MW unit constructed in 1951, Unit #2 is an 80 MW unit constructed in 1952, and Unit #3 is a 105 MW unit constructed in 1955. Fuel oil may be used in Units #1, #2, and #3 as a back-up fuel during natural gas curtailments. Units #1 and #2 are equipped with low NOX burners. Three 43.5 MW LM 6000 natural gas-fueled simple cycle gas turbine engines (Units #4, #5, and #6) were added in 2002 and are subject to New Source Performance Standards (NSPS) Subparts A and GG. The plant is a $PM_{10}$ SIP source located in a $PM_{10}$ nonattainment area and an ozone maintenance area. The plant is also a Phase II Acid Rain source and a major source of NOX and CO.

UTAH AIR QUALITY BOARD

| By: | Prepared By: |
|---|---|
| Richard W. Sprott, Executive Secretary | Jennifer He |

# Operating Permit History

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|---|---|---|
| 2/9/1999 - Permit issued | Action initiated by an initial operating permit application | |
| 5/17/2001 -Permit modified | Action initiated by an administrative amendment (initiated by source) | to include revisions resulting from issuance of Approval Orders DAQE-250-01 and DAQE-263-01 for location of skid-mounted turbines at this source. |
| 1/31/2002 -Permit modified | Action initiated by an administrative amendment (initiated by DAQ) | issuance of AO DAQE-067-02 for changing $PM_{10}$ emission factor for three boilers, removing non-existing units #14 and #19, changing certification date to April 1, 1999, and removing all the conditions associated with temporary portable plant. |
| 6/14/2002 -Permit modified | Action initiated by an administrative amendment (initiated by DAQ) | issuance of AO DAQE-204-02 for adding 3 natural gas turbines. |
| 10/28/2002 -Permit modified | Action initiated by a significant operating permit modification | to include the NSPS subpart GG alternative monitoring, approved by EPA in the letters dated July 19 and August 29, 2002, into the permit. |
| 4/2/2003 -Permit modified | Action initiated by a significant operating permit modification | to remove Cold Degreasing Operations Unit from the permit and modify reporting frequency for some emission units with continuous emission monitoring (CEM). |
| 8/20/2004 - Permit drafted | Action initiated by a renewal of an operating permit | The 40 CFR Part 75 requirement for CO CEMS is removed from the natural gas simple cycle turbines (EU#24). $NO_x$ emission calculations are modified for all three steam generating units and both $NO_x$ limits (ppmdv and lb/hr) are required to demonstrate compliance continuously in the renewal permit. Amendments to NSPS GG (7/8/04) are included in the permit. |

# Table of Contents

**Issued under authority of Utah Code Ann. Section 19-2-104 and 19-2-109.1, and in accordance with Utah Administrative Code R307-415 Operating Permit Requirements.**

All definitions, terms and abbreviations used in this permit conform to those used in Utah Administrative Code R307-101 and R307-415 (Rules), and 40 Code of Federal Regulations (CFR), except as otherwise defined in this permit. Unless noted otherwise, references cited in the permit conditions refer to the Rules.

Where a permit condition in Section I, General Provisions, partially recites or summarizes an applicable rule, the full text of the applicable portion of the rule shall govern interpretations of the requirements of the rule. In the case of a conflict between the Rules and the permit terms and conditions of Section II, Special Provisions, the permit terms and conditions of Section II shall govern except as noted in Provision I.M, Permit Shield.

# Section I: General Provisions

I.A. **Federal Enforcement.**

All terms and conditions in this permit, including those provisions designed to limit the potential to emit, are enforceable by the EPA and citizens under the Clean Air Act of 1990 (CAA) except those terms and conditions that are specifically designated as "State Requirements". (R307-415-6b)

I.B. **Permitted Activity(ies).**

Except as provided in R307-415-7b(1), the permittee may not operate except in compliance with this permit. (See also Provision I.E, Application Shield)

I.C. **Duty to Comply.**

I.C.1 The permittee must comply with all conditions of the operating permit. Any permit noncompliance constitutes a violation of the Air Conservation Act and is grounds for any of the following: enforcement action; permit termination; revocation and reissuance; modification; or denial of a permit renewal application. (R307-415-6a(6)(a))

I.C.2 It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. (R307-415-6a(6)(b))

I.C.3 The permittee shall furnish to the Executive Secretary, within a reasonable time, any information that the Executive Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Executive Secretary copies of records required to be kept by this permit or, for information claimed to be confidential, the permittee may furnish such records directly to the EPA along with a claim of confidentiality. (R307-415-6a(6)(e))

I.C.4 This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance shall not stay any permit condition, except as provided under R307-415-7f(1) for minor permit modifications. (R307-415-6a(6)(c))

I.D. **Permit Expiration and Renewal.**

I.D.1 **This permit is issued for a fixed term of five years and expires on (Assigned in Final Permit)**. (R307-415-6a(2))

I.D.2 Application for renewal of this permit is due by (Assigned in Final Permit). An application may be submitted early for any reason. (R307-415-5a(1)(c))

I.D.3 An application for renewal submitted after the due date listed in I.D.2 above shall be accepted for processing, but shall not be considered a timely application and shall not relieve the permittee of any enforcement actions resulting from submitting a late application. (R307-415-5a(5))

I.D.4 Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted consistent with R307-415-7b (see also Provision I.E, Application Shield) and R307-415-5a(1)(c) (see also Provision I.D.2). (R307-415-7c(2))

I.E. **Application Shield.**

If the permittee submits a timely and complete application for renewal, the permittee's failure to have an operating permit will not be a violation of R307-415, until the Executive Secretary takes final action on the permit renewal application. In such case, the terms and conditions of this permit shall remain in force until permit renewal or denial. This protection shall cease to apply if, subsequent to the completeness determination required pursuant to R307-415-7a(3), and as required by R307-415-5a(2), the applicant fails to submit by the deadline specified in writing by the Executive Secretary any additional information identified as being needed to process the application. (R307-415-7b(2))

I.F. **Severability.**

In the event of a challenge to any portion of this permit, or if any portion of this permit is held invalid, the remaining permit conditions remain valid and in force. (R307-415-6a(5))

I.G. **Permit Fee.**

I.G.1 The permittee shall pay an annual emission fee to the Executive Secretary consistent with R307-415-9. (R307-415-6a(7))

I.G.2 The emission fee shall be due on October 1 of each calendar year or 45 days after the source receives notice of the amount of the fee, whichever is later. (R307-415-9(4)(a))

I.H. **No Property Rights.**

This permit does not convey any property rights of any sort, or any exclusive privilege. (R307-415-6a(6)(d))

I.I. **Revision Exception.**

No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit. (R307-415-6a(8))

I.J. **Inspection and Entry.**

I.J.1 Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Executive Secretary or an authorized representative to perform any of the following:

I.J.1.a Enter upon the permittee's premises where the source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit. (R307-415-6c(2)(a))

I.J.1.b Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit. (R307-415-6c(2)(b))

I.J.1.c Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practice, or operation regulated or required under this permit. (R307-415-6c(2)(c))

I.J.1.d Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with this permit or applicable requirements. (R307-415-6c(2)(d))

I.J.2 Any claims of confidentiality made on the information obtained during an inspection shall be made pursuant to Utah Code Ann. Section 19-1-306. (R307-415-6c(2)(e))

I.K. **Certification.**

Any application form, report, or compliance certification submitted pursuant to this permit shall contain certification as to its truth, accuracy, and completeness, by a responsible official as defined in R307-415-3. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. (R307-415-5d)

I.L. **Compliance Certification.**

I.L.1 Permittee shall submit to the Executive Secretary an annual compliance certification, certifying compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. This certification shall be submitted no later than **April 1, 1999** and that date each year following until this permit expires. The certification shall include all the following (permittee may cross-reference this permit or previous reports): (R307-415-6c(5))

I.L.1.a The identification of each term or condition of this permit that is the basis of the certification;

I.L.1.b The identification of the methods or other means used by the permittee for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the monitoring and related recordkeeping and reporting requirements in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information;

I.L.1.c The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in Provision I.L.1.b. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred; and

I.L.1.d Such other facts as the Executive Secretary may require to determine the compliance status.

I.L.2 The permittee shall also submit all compliance certifications to the EPA, Region VIII, at the following address or to such other address as may be required by the Executive Secretary: (R307-415-6c(5)(d))

Office of Enforcement, Compliance and Environmental Justice
(mail code 8ENF)
EPA, Region VIII
999 18th Street, Suite 300
Denver, CO 80202-2466

I.M. **Permit Shield.**

I.M.1 Compliance with the provisions of this permit shall be deemed compliance with any applicable requirements as of the date of this permit, provided that:

I.M.1.a Such applicable requirements are included and are specifically identified in this permit, or (R307-415-6f(1)(a))

I.M.1.b Those requirements not applicable to the source are specifically identified and listed in this permit. (R307-415-6f(1)(b))

I.M.2 Nothing in this permit shall alter or affect any of the following:

I.M.2.a The emergency provisions of Utah Code Ann. Section 19-1-202 and Section 19-2-112, and the provisions of the CAA Section 303. (R307-415-6f(3)(a))

I.M.2.b The liability of the owner or operator of the source for any violation of applicable requirements under Utah Code Ann. Section 19-2-107(2)(g) and Section 19-2-110 prior to or at the time of issuance of this permit. (R307-415-6f(3)(b)

I.M.2.c The applicable requirements of the Acid Rain Program, consistent with the CAA Section 408(a). (R307-415-6f(3)(c))

I.M.2.d The ability of the Executive Secretary to obtain information from the source under Utah Code Ann. Section 19-2-120, and the ability of the EPA to obtain information from the source under the CAA Section 114. (R307-415-6f(3)(d))

I.N. **Emergency Provision.**

I.N.1 An “emergency” is any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. (R307-415-6g(1))

I.N.2 An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the affirmative defense is demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

I.N.2.a An emergency occurred and the permittee can identify the causes of the emergency. (R307-415-6g(3)(a))

I.N.2.b The permitted facility was at the time being properly operated. (R307-415-6g(3)(b))

I.N.2.c During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in this permit. (R307-415-6g(3)(c))

I.N.2.d The permittee submitted notice of the emergency to the Executive Secretary within two working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirement of Provision I.S.2.c below. (R307-415-6g(3)(d))

I.N.3 In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof. (R307-415-6g(4))

I.N.4 This emergency provision is in addition to any emergency or upset provision contained in any other section of this permit. (R307-415-6g(5))

**I.O. Operational Flexibility.**

Operational flexibility is governed by R307-415-7d(1).

**I.P. Off-permit Changes.**

Off-permit changes are governed by R307-415-7d(2).

**I.Q. Administrative Permit Amendments.**

Administrative permit amendments are governed by R307-415-7e.

**I.R. Permit Modifications.**

Permit modifications are governed by R307-415-7f.

**I.S. Records and Reporting.**

I.S.1 Records.

I.S.1.a The records of all required monitoring data and support information shall be retained by the permittee for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-charts or appropriate recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. (R307-415-6a(3)(b)(ii)

I.S.1.b For all monitoring requirements described in Section II, Special Provisions, the source shall record the following information, where applicable: (R307-415-6a(3)(b)(i))

I.S.1.b.1 The date, place as defined in this permit, and time of sampling or measurement.

I.S.1.b.2 The date analyses were performed.

I.S.1.b.3 The company or entity that performed the analyses.

I.S.1.b.4 The analytical techniques or methods used.

I.S.1.b.5 The results of such analyses.

I.S.1.b.6 The operating conditions as existing at the time of sampling or measurement.

I.S.1.c Additional record keeping requirements, if any, are described in Section II, Special Provisions.

I.S.2 Reports.

I.S.2.a Monitoring reports shall be submitted to the Executive Secretary every six months, or more frequently if specified in Section II. All instances of deviation from permit requirements shall be clearly identified in the reports. (R307-415-6a(3)(c)(i))

I.S.2.b All reports submitted pursuant to Provision I.S.2.a shall be certified by a responsible official in accordance with Provision I.K of this permit. (R307-415-6a(3)(c)(i)

I.S.2.c The Executive Secretary shall be notified promptly of any deviations from permit requirements including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventative measures taken. **Prompt, as used in this condition, shall be defined as written notification within 14 days**. Deviations from permit requirements due to unavoidable breakdowns shall be reported in accordance with the provisions of R307-107. (R307-415-6a(3)(c)(ii))

I.S.3 Notification Addresses.

I.S.3.a All reports, notifications, or other submissions required by this permit to be submitted to the Executive Secretary are to be sent to the following address or to such other address as may be required by the Executive Secretary:

Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820
Phone: 801-536-4000

I.S.3.b All reports, notifications or other submissions required by this permit to be submitted to the EPA should be sent to one of the following addresses or to such other address as may be required by the Executive Secretary:

For annual compliance certifications

Environmental Protection Agency, Region VIII
Office of Enforcement, Compliance and Environmental Justice (mail code 8ENF)
999 18th Street, Suite 300
Denver, CO 80202-2466

For reports, notifications, or other correspondence related to permit modifications, applications, etc.

Environmental Protection Agency, Region VIII
Office of Partnerships & Regulatory Assistance
Air & Radiation Program (mail code 8P-AR)
999 18th Street, Suite 300
Denver, CO 80202-2466
Phone: 303-312-6440

I.T. **Reopening for Cause.**

I.T.1 A permit shall be reopened and revised under any of the following circumstances:

I.T.1.a New applicable requirements become applicable to the permittee and there is a remaining permit term of three or more years. No such reopening is required if the effective date of the requirement is later than the date on which this permit is due to expire, unless the terms and conditions of this permit have been extended pursuant to R307-415-7c(3), application shield. (R307-415-7g(1)(a))

I.T.1.b The Executive Secretary or EPA determines that this permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit. (R307-415-7g(1)(c))

I.T.1.c EPA or the Executive Secretary determines that this permit must be revised or revoked to assure compliance with applicable requirements. (R307-415-7g(1)(d))

I.T.1.d Additional applicable requirements are to become effective before the renewal date of this permit and are in conflict with existing permit conditions. (R307-415-7g(1)(e))

I.T.2 Additional requirements, including excess emissions requirements, become applicable to a Title IV affected source under the Acid Rain Program. Upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into this permit. (R307-415-7g(1)(b)) To be deleted unless a Title IV source.

I.T.3 Proceedings to reopen and issue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. (R307-415-7g(2))

I.U. **Inventory Requirements.**

Emission inventories shall be submitted in accordance with the procedures of R307-150, Emission Inventories. (R307-150)

I.V. **Title IV and Other, More Stringent Requirements**

Where an applicable requirement is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, Acid Deposition Control, both provisions shall be incorporated into this permit. (R307-415-6a(1)(b))

# Section II: SPECIAL PROVISIONS

**II.A. Emission Unit(s) Permitted to Discharge Air Contaminants.**

(R307-415-4(3)(a) and R307-415-4(4))

II.A.1 **Steam Generating Unit #1** (designated as Emission unit #1)

Unit Description: 65 MW electric generator powered by 726 MMBtu/hr capacity natural gas (NG)-fired utility boiler, equipped with low $NO_x$ burners. No. 2 fuel oil may be used as back-up fuel during NG curtailments and maintenance firings.

II.A.2 **Steam Generating Unit #2** (designated as Emission unit #2)

Unit Description: 80 MW electric generator powered by 825 MMBtu/hr capacity NG-fired utility boiler, equipped with low $NO_x$ burners. No. 2 fuel oil may be used as back-up fuel during NG curtailments and maintenance firings.

II.A.3 **Steam Generating Unit #3** (designated as Emission unit #3)

Unit Description: 105 MW electric generator powered by 1,155 MMBtu/hr capacity NG-fired utility boiler. No. 2 fuel oil may be used as back-up fuel during NG curtailments and maintenance firings.

II.A.4 **Steam Generating Units** (designated as Emission unit #4)

Unit Description: Combined emission unit group consisting of Steam Generating Units #1, #2, and #3.

II.A.5 **Abrasive Blasting Operation** (designated as Emission unit #5)

Unit Description: portable sand blaster, includes two glove box units with fabric filters, for maintenance and painting operation. No unit-specific applicable requirements.

II.A.6 **Emission Unit #1 Cooling Towers** (designated as Emission unit #7)

Unit Description: Cooling towers for the circulating water system for Emission Unit #1. No unit-specific applicable requirements.

II.A.7 **Emission Unit #2 Cooling Towers** (designated as Emission unit #8)

Unit Description: Cooling towers for the circulating water system for Emission Unit #2. No unit-specific applicable requirements.

II.A.8 **Emission Unit #3 Cooling Towers** (designated as Emission unit #9)

Unit Description: Cooling towers for the circulating water system for Emission Unit #3. No unit-specific applicable requirements.

II.A.9 **Emergency Generator (diesel engine)** (designated as Emission unit #10)

Unit Description: 175 kW emergency generator powered by a 280 hp diesel engine. No unit-specific applicable requirements.

II.A.10 **Distillate Fuel Oil Tank** (designated as Emission unit #11)

Unit Description: One 500 gallon tank for emergency equipment. No unit-specific applicable requirements.

II.A.11 **Lube Oil Storage Tanks** (designated as Emission unit #12)

Unit Description: Two 4,200 gallon tanks including vents and associated equipment that store lubricating oil. No unit-specific applicable requirements.

II.A.12 **Oil Storage Area** (designated as Emission unit #13)

Unit Description: Storage area for oil contained in closed 55 gallon drums. No unit-specific applicable requirements.

II.A.13 **Miscellaneous Electrical Equipment** (designated as Emission unit #15)

Unit Description: Stores transformer insulating oil. No unit-specific applicable requirements.

II.A.14 **Water Treatment Chemical Tanks** (designated as Emission unit #16)

Unit Description: Closed tanks to store water treatment chemicals. No unit-specific applicable requirements.

II.A.15 **Paint Storage Areas** (designated as Emission unit #17)
Unit Description: Various storage areas for sealed paint containers. No unit-specific applicable requirements.

II.A.16 **Miscellaneous Parts Painting for Maintenance** (designated as Emission unit #18)
Unit Description: Incidental preventative maintenance painting of parts for process equipment totaling less than 1.0 ton per year of VOC and 500 pounds per year of HAPs. No unit-specific applicable requirements.

II.A.17 **Lube Oil Conditioners** (designated as Emission unit #20)
Unit Description: Three 975-gallon lube oil conditioner vessels with vapor extractors to maintain the oil purity. No unit-specific applicable requirements.

II.A.18 **Lube Oil Reservoirs** (designated as Emission unit #21)
Unit Description: Three lube oil reservoirs (two 2,800 gallon and one 3,150 gallon) with vapor extractors. No unit-specific applicable requirements.

II.A.19 **Hazardous Waste Storage Area** (designated as Emission unit #22)
Unit Description: Area where hazardous waste is stored temporarily awaiting disposal. No unit-specific applicable requirements.

II.A.20 **Water Treatment Sludge Disposal Activities** (designated as Emission unit #23)
Unit Description: Disposal of sludge generated from water treatment. No unit-specific applicable requirements.

II.A.21 **Natural Gas Simple Cycle Turbines Units** (designated as Emission unit #24)
Unit Description: Three GE LM6000 PC Sprint natural gas simple cycle turbines (Unit #4, #5, & #6), each output rate at 43.5 MW and maximum firing rate at 367.6 MM Btu/hr, with water injection, $NO_x$ SCR catalyst and CO oxidation catalyst.

## II.B. Requirements and limitations.

The following emission limitations, standards, and operational limitations apply to the permitted facility as indicated: (R307-415-6a(1))

### II.B.1 <u>Conditions on permitted source (Source-wide)</u>

II.B.1.a **Condition:**

Visible emissions shall be no greater than 20 percent opacity for all particulate emission sources unless otherwise noted in this permit. Fugitive dust shall be no greater than 20 percent opacity. [Authority granted under Utah SIP IX.H.2.a.B and R307-305-1; condition originated in Utah SIP IX.H.2.a.B and R307-305-1]

II.B.1.a.1 **Monitoring:**

A visual observation of each emission unit indicated above shall be conducted on a weekly basis. The observation may be completed as a general overview of the facility. If any visible emissions are noted then an observation of that emission unit shall be performed by an individual trained on the requirements of 40 CFR 60, Appendix A, Method 9. The individual is not required to be a certified visible emissions observer (VEO). If the above observation(s) indicate that visible emissions are still present then further observations must be performed by a certified VEO in accordance with 40 CFR 60, Appendix A, Method 9 or 58 FR 61640 Method 203C as appropriate, within 24 hours of the initial observation.

II.B.1.a.2 **Recordkeeping:**

An operator's log shall be maintained of all monitoring provisions listed above. The records shall contain all applicable information as required by section I.S.1 of this permit.

II.B.1.a.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.1.b **Condition:**

At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected emission unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [Authority granted under R307-401-6(1) [BACT] & R307-401-5; condition originated in DAQE-204-02]

II.B.1.b.1 **Monitoring:**

Records required for this permit condition will serve as monitoring.

II.B.1.b.2 **Recordkeeping:**

Permittee shall document activities performed to assure proper operation and maintenance. Records shall be maintained in accordance with Provision I.S.1 of this permit.

II.B.1.b.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.1.c **Condition:**

The permittee shall comply with the applicable requirements for recycling and emission reduction for class I and class II refrigerants pursuant to 40 CFR 82, Subpart F - Recycling and Emissions Reduction. [Authority granted under 40 CFR 82.150(b); condition originated in 40 CFR Part 82]

II.B.1.c.1 **Monitoring:**

The permittee shall certify, in the annual compliance statement required in Section I of this permit, its compliance status with the requirements of 40 CFR 82, Subpart F.

II.B.1.c.2 **Recordkeeping:**

All records required in 40 CFR 82, Subpart F shall be maintained consistent with the requirements of Provision S.1 in Section I of this permit.

II.B.1.c.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.1.d **Condition:**

Visible emissions shall not exceed 40 percent opacity for more than three minutes in any one hour if the permittee is complying with one of the performance standards listed below. If the permittee is not complying with one of the performance standards listed below, visible emissions shall not exceed 20 percent opacity for more than three minutes in any one hour.

(a) Any abrasive blasting operation may use at least one of the following performance standards:

(1) Confined blasting;
(2) Wet abrasive blasting;
(3) Hydroblasting; or
(4) Unconfined blasting using abrasives as defined in paragraph (b).

(b) Abrasives used for dry unconfined blasting referenced in paragraph (a)(4) above shall comply with the following performance standards:

(1) Before blasting the abrasive shall not contain more than 1% by weight material passing a #70 U.S. Standard sieve.
(2) After blasting the abrasive shall not contain more than 1.8% by weight material 5 micron or smaller.
(3) Abrasives reused for dry unconfined blasting are exempt from paragraph (b)(2), but must conform with paragraph (b)(1).

(c) Sources using the performance standard of paragraph (a)(4) must demonstrate that the abrasives were obtained from persons that have certified (submitted test results) to the executive secretary at least annually that such abrasives meet the requirements of paragraph (b) above (ref. R307-206.). [Authority granted under R307-206; condition originated in R307-206]

II.B.1.d.1 **Monitoring:**

Visible emission evaluation of abrasive blasting operations shall be conducted at least quarterly in accordance Provision I.S.1 of this permit and the following provisions:

(a) EPA proposed method 203B shall be used for all observations;

(b) Evaluations shall be conducted by a person certified in accordance with 40 CFR 60, Appendix A, Method 9;

(c) Observations shall be conducted for a period of no less than three minutes but no more than one hour, in accordance with the applicable time period for this provision;

(d) Emissions from unconfined blasting shall be read at the densest point of the emission after a major portion of the spent abrasive has fallen out, at a point not less than five feet nor more than twenty-five feet from the impact surface from any single abrasive blasting nozzle;

(e) Emissions from unconfined blasting employing multiple nozzles shall be judged as a single source unless it can be demonstrated by the owner or operator that each nozzle, evaluated separately, meets the emission and performance standards of this provision;

(f) Emissions from confined blasting shall be read at the densest point after the air contaminant leaves the enclosure.

II.B.1.d.2 **Recordkeeping:**

Records of visible emissions evaluations and documentation that demonstrates adherence to the performance standards in R307-206-4 shall be maintained.

II.B.1.d.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.2 **Conditions on Steam Generating Unit #1 (Emission unit #1)**

II.B.2.a **Condition:**

Emissions of $NO_x$ shall be no greater than 179 lbs/hour and 336 ppmdv (3% $O_2$, dry). [Authority granted under Utah SIP Section IX.H.2.b.BBB; condition originated in DAQE-204-02]

II.B.2.a.1 **Monitoring:**

a. The permittee shall determine compliance with the $NO_x$ limits by calculating arithmetic average of three contiguous one-hour periods $NO_x$ emission rate (lb/hr) or concentration (ppmdv, 3% $O_2$ dry) generated from paragraph b of this section.
b. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for $NO_x$ and $CO_2$ as required by 40 CFR Part 75 for the Acid Rain Program. The hourly average $O_2$ concentration (percent by volume) shall be calculated from $CO_2$ concentration obtained from $CO_2$ CEMS in accordance with 40 CFR Part 75, Appendix F. The $NO_x$ concentration (ppm) obtained from $NO_x$ CEMS shall be corrected to 3% $O_2$ on hourly basis using the $O_2$ data calculated above. The emission rate (lb/hr) shall be calculated by multiplying the hourly average $NO_x$ emission rate (lb/MMBtu) by the hourly heat input (MMBtu/hr). The hourly average $NO_x$ emission rate (lb/MMBTU) shall be calculated by using $NO_x$ and $CO_2$ concentrations obtained from CEMS in accordance with 40 CFR Part 75, Appendix F. The heat input shall be calculated by multiplying the measured fuel flow rate (scf/hr) by the hourly average $CO_2$ concentration (percent by volume) and by any necessary conversion factors in accordance with 40 CFR Part 75, Appendix F.
c. Each continuous emission monitoring system shall meet the Specifications and Test Procedures required by 40 CFR Part 75, Appendix A.
d. The permittee shall implement Quality Assurance and Quality Control Procedures required by 40 CFR Part 75, Appendix B.

II.B.2.a.2 **Recordkeeping:**

The permittee shall maintain a file of all measurements and calculations, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices recorded in a permanent form suitable for inspection.

II.B.2.a.3 **Reporting:**

The permittee shall comply with the reporting provisions in R307-170-9 and 40 CFR 75 Subpart G, and all the reporting provisions contained in Section I of this permit. The quarterly reports required in R307-170-9 and 40 CFR 75 Subpart G are considered prompt notification of permit deviations required in Provision I.S.2.c of this permit if all information required by Provision I.S.2.c is included in the report.

II.B.3 **<u>Conditions on Steam Generating Unit #2 (Emission unit #2)</u>**

II.B.3.a **Condition:**

Emissions of $NO_x$ shall be no greater than 204 lbs/hour and 336 ppmdv (3% $O_2$, dry). [Authority granted under Utah SIP Section IX.H.2.b.BBB; condition originated in DAQE-204-02]

II.B.3.a.1 **Monitoring:**

a. The permittee shall determine compliance with the $NO_x$ limits by calculating arithmetic average of three contiguous one-hour periods $NO_x$ emission rate (lb/hr) or concentration (ppmdv, 3% $O_2$ dry) generated from paragraph b of this section.
b. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for $NO_x$ and $CO_2$ as required by 40 CFR Part 75 for the Acid Rain Program. The hourly average $O_2$ concentration (percent by volume) shall be calculated from $CO_2$ concentration obtained from $CO_2$ CEMS in accordance with 40 CFR Part 75, Appendix F. The $NO_x$ concentration (ppm) obtained from $NO_x$ CEMS shall be corrected to 3% $O_2$ on hourly basis using the $O_2$ data calculated above. The emission rate (lb/hr) shall be calculated by multiplying the hourly average $NO_x$ emission rate (lb/MMBtu) by the hourly heat input (MMBtu/hr). The hourly average $NO_x$ emission rate (lb/MMBTU) shall be calculated by using $NO_x$ and $CO_2$ concentrations obtained from CEMS in accordance with 40 CFR Part 75, Appendix F. The heat input shall be calculated by multiplying the measured fuel flow rate (scf/hr) by the hourly average $CO_2$ concentration (percent by volume) and by any necessary conversion factors in accordance with 40 CFR Part 75, Appendix F.
c. Each continuous emission monitoring system shall meet the Specifications and Test Procedures required by 40 CFR Part 75, Appendix A.
d. The permittee shall implement Quality Assurance and Quality Control Procedures required by 40 CFR Part 75, Appendix B.

II.B.3.a.2 **Recordkeeping:**

The permittee shall maintain a file of all measurements and calculations, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices recorded in a permanent form suitable for inspection.

II.B.3.a.3 **Reporting:**

The permittee shall comply with the reporting provisions in R307-170-9 and 40 CFR 75 Subpart G, and all the reporting provisions contained in Section I of this permit. The quarterly reports required in R307-170-9 and 40 CFR 75 Subpart G are considered prompt notification of permit deviations required in Provision I.S.2.c of this permit if all information required by Provision I.S.2.c is included in the report.

II.B.4 **<u>Conditions on Steam Generating Unit #3 (Emission unit #3)</u>**

II.B.4.a **Condition:**

Emissions of $NO_x$ shall be no greater than 142 lbs/hour and 168 ppmdv (3% $O_2$, dry) from November 1 through February 28 (29). Emissions of $NO_x$ shall be no greater than 203 lbs/hour and 168 ppmdv (3% $O_2$, dry) from March 1 through October 31. [Authority granted under Utah SIP IX.H.2.b.BBB; condition originated in DAQE-204-02]

II.B.4.a.1 **Monitoring:**

a. The permittee shall determine compliance with the $NO_x$ limits by calculating arithmetic average of three contiguous one-hour periods $NO_x$ emission rate (lb/hr) or concentration (ppmdv, 3% $O_2$ dry) generated from paragraph b of this section.
b. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for $NO_x$ and $CO_2$ as required by 40 CFR Part 75 for the Acid Rain Program. The hourly average $O_2$ concentration (percent by volume) shall be calculated from $CO_2$ concentration obtained from $CO_2$ CEMS in accordance with 40 CFR Part 75, Appendix F. The $NO_x$ concentration (ppm) obtained from $NO_x$ CEMS shall be corrected to 3% $O_2$ on hourly basis using the $O_2$ data calculated above. The emission rate (lb/hr) shall be calculated by multiplying the hourly average $NO_x$ emission rate (lb/MMBtu) by the hourly heat input (MMBtu/hr). The hourly average $NO_x$ emission rate (lb/MMBTU) shall be calculated by using $NO_x$ and $CO_2$ concentrations obtained from CEMS in accordance with 40 CFR Part 75, Appendix F. The heat input shall be calculated by multiplying the measured fuel flow rate (scf/hr) by the hourly average $CO_2$ concentration (percent by volume) and by any necessary conversion factors in accordance with 40 CFR Part 75, Appendix F.
c. Each continuous emission monitoring system shall meet the Specifications and Test Procedures required by 40 CFR Part 75, Appendix A.
d. The permittee shall implement Quality Assurance and Quality Control Procedures required by 40 CFR Part 75, Appendix B.

d. The quality assurance requirements of R307-170, Continuous Emission Monitoring Systems Program, shall be used in addition to 40 CFR Part 75 procedures to fulfill data quality assurance requirements.

II.B.4.a.2 **Recordkeeping:**

The permittee shall maintain a file of all measurements and calculations, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices recorded in a permanent form suitable for inspection.

II.B.4.a.3 **Reporting:**

The permittee shall comply with the reporting provisions in R307-170-9 and 40 CFR 75 Subpart G, and all the reporting provisions contained in Section I of this permit. The quarterly reports required in R307-170-9 and 40 CFR 75 Subpart G are considered prompt notification of permit deviations required in Provision I.S.2.c of this permit if all information required by Provision I.S.2.c is included in the report.

II.B.5 **<u>Conditions on Steam Generating Units (Emission unit #4)</u>**

II.B.5.a **Condition:**

Sulfur content of any fuel oil burned shall be no greater than 0.45 % by weight. [Authority granted under Utah SIP Section IX.H.2.b.BBB; condition originated in DAQE-204-02]

II.B.5.a.1 **Monitoring:**

Sulfur content shall be determined either by testing each fuel delivery of fuel oil or by inspection of the fuel sulfur-content specifications provided by the vendor in purchase records. Sulfur content in either instance shall be determined in accordance with ASTM-D-4294, or equivalent.

II.B.5.a.2 **Recordkeeping:**

Results of monitoring shall be maintained in accordance with Provision I.S.1 of this permit.

II.B.5.a.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.5.b **Condition:**

Visible emissions shall be no greater than 10 percent opacity for each stack. [Authority granted under Utah SIP IX.H.2.a.B; condition originated in DAQE-204-02]

II.B.5.b.1 **Monitoring:**

In lieu of monitoring via visible emission observations, fuel usage shall be monitored to demonstrate that only natural gas is used as fuel. A 40 CFR Part 60, Method 9 test will be conducted at least once every 24 hours during each period of natural gas curtailment over 24 hours in length when the unit is operated on fuel oil.

II.B.5.b.2 **Recordkeeping:**

Results of monitoring shall be maintained in accordance with Provision I.S.1 of this permit.

II.B.5.b.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.5.c **Condition:**

The permittee shall use only natural gas as a primary fuel and No. 2 fuel oil or lighter or combination of No. 1 and No. 2 fuel oil as back-up fuel. The fuel oil may be used only during periods of natural gas curtailment and for maintenance firings. Maintenance firings shall not exceed one-percent of the annual plant BTU requirement. In addition, maintenance firings shall be scheduled between April 1 and November 30 of any calendar year. Natural gas curtailment is defined as period when the natural gas provider/supplier imposes a curtailment or interruption of service, and the curtailment is involuntary and beyond the control of the permittee. [Authority granted under Utah SIP IX.H.2.b.BBB; condition originated in DAQE-204-02]

II.B.5.c.1 **Monitoring:**

Records required for this permit condition will serve as monitoring.

II.B.5.c.2 **Recordkeeping:**

The permittee shall maintain records that document the reason (NG curtailment or maintenance), date, duration, quantity consumed for each firing, and BTU content of fuel oil during each firing. The percentage of the heat input during maintenance firings shall be calculated as follow:

The percent of the heat input during maintenance firing = (Sum of the heat input (MMBtu) of all three boilers during maintenance firings of a calendar year)/ (2706 MMBtu/hrx8760 hrs) x 100

II.B.5.c.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.5.d **Condition:**

Emissions of $PM_{10}$ shall be no greater than 44.39 tons per rolling 12-month period. [Authority granted under R307-401-6(1) [BACT]; condition originated in DAQE-204-02]

II.B.5.d.1 **Monitoring:**

The emissions shall be determined on a rolling 12-month total. Within the first 10 days of each month, the total shall be calculated for each calendar month and added to the previous 11 months data.

Monthly emissions shall be the sum of emissions from each boiler and shall be calculated using the following equation:

Monthly emissions (tons) =[(ft3/month)* x 5.0 (lb/10^6 ft3) x (1 ton/2000 lbs)] + [(gal/month)** x 3.5 (lb/1000 gal) x (1 ton/2000 lbs)]

* natural gas consumed by all boilers combined during one month
** #2 diesel fuel consumed by all boilers combined during one month

Fuel consumption shall be determined by examination of the fuel usage records.

II.B.5.d.2 **Recordkeeping:**

Records such as gas/#2 diesel bills, or gas meter readings shall be kept on a daily basis and used to demonstrate natural gas/#2 diesel usage. Records shall be maintained as described in Provision I.S of this permit.

II.B.5.d.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.6 **<u>Conditions on Natural Gas Simple Cycle Turbines Units (Emission unit #24)</u>**

II.B.6.a **Condition:**

The permittee shall comply with all applicable requirements of 40 CFR 60 Subpart A. [Authority granted under 40 CFR 60 (Subpart A); condition originated in DAQE-204-02]

II.B.6.a.1 **Monitoring:**

The permittee shall comply with the monitoring requirements of 40 CFR 60.8(a), (b), (c), (e) and (f), and 60.11(a). (origin: 40 CFR 60 Subpart A)

II.B.6.a.2 **Recordkeeping:**

The permittee shall comply the recordkeeping requirements of provision I.S.1 of this permit and any additional recordkeeping requirements of 40 CFR 60.7. (origin: 40 CFR 60 Subpart A)

II.B.6.a.3 **Reporting:**

The permittee shall comply with the reporting requirements in Section I of this permit and any additional reporting and notification requirements of 40 CFR 60 Subpart A. (origin: 40 CFR 60 Subpart A)

II.B.6.b **Condition:**

Total emissions of $NO_x$ from all three turbines shall be no greater than 22.2 lbs/hour (15% $O_2$, dry) based on 30 day rolling average under steady state operation (not including startup and shutdown). Emission of $NO_x$ from each individual turbine shall be no greater than 5 ppmdv (15% $O_2$, dry) based on 30 day rolling average under steady state operation (not including startup and shutdown) and shall be no greater than 116 ppmdv (15% $O_2$, dry) at any time. [Authority granted under R307- 401- 6(1) [BACT] & 40 CFR 60.332 (Subpart GG); condition originated in DAQE-204-02]

II.B.6.b.1 **Monitoring:**

(a) The permittee should install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of $NO_x$ and $O_2$ monitors. The CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the $NO_x$ and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for $NO_x$) and a percent $O_2$ basis for oxygen; or

(ii) On a ppm at 15 percent $O_2$ basis.

(2) As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (a)(2) of this section, is obtained for both $NO_x$ and diluent, the data acquisition and handling system must calculate and record the hourly $NO_x$ emissions in the units of percent $NO_x$ by volume, dry basis, corrected to 15 percent $O_2$ and International Organization for Standardization (ISO) standard conditions (if required as given in 40 CFR 60.335(b)(1)). For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$, a diluent cap value of 19.0 percent $O_2$ may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

(iii) If the permitteer has installed a $NO_x$ CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in Sec. 60.7(c).

(b) Each continuous emission monitoring system shall meet the Specifications and Test Procedures required by 40 CFR Part 75, Appendix A.

(c) The permittee shall implement Quality Assurance and Quality Control Procedures required by 40 CFR Part 75, Appendix B.

(d) The quality assurance requirements of R307-170, Continuous Emission Monitoring Systems Program, shall be used in addition to 40 CFR Part 75 procedures to fulfill data quality assurance requirements.

(f) The daily average of $NO_x$ emissions shall be calculated once for each day and the 30-day rolling average shall be calculated by adding previous 30 days data on a daily basis.

II.B.6.b.2 **Recordkeeping:**

Results of $NO_x$ monitoring shall be recorded and maintained as required in R307-170, 40 CFR 60 subpart GG, 40 CFR 75 subpart F, and as described in Provision I.S.1 of this permit.

II.B.6.b.3 **Reporting:**

The permittee shall comply with the reporting provisions in R307-170-9, 40 CFR 75 Subpart G, 40 CFR Subpart GG and all the reporting provisions contained in Section I of this permit.

The permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(a) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average $NO_x$ concentration exceeds applicable NSPS emission standard of 116 ppmdv (15% $O_2$, dry). A ``4-hour rolling average $NO_x$ concentration'' is the arithmetic average of the average $NO_x$ concentration measured by the CEMS for a given hour (corrected to 15 percent $O_2$ and, if required under 40 CFR 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average $NO_x$ concentrations immediately preceding that unit operating hour.

(b) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either $NO_x$ concentration or diluent (or both).

(c) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period. The ambient conditions is not required if the permittee opt to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii).

(d) All reports of excess emissions and monitor downtime shall be postmarked by the 30th day following the end of each calendar quarter.

The quarterly reports required in R307-170-9 and 40 CFR 75 Subpart G are considered prompt notification of permit deviations required in Provision I.S.2.c of this permit if all information required by Provision I.S.2.c is included in the report.

II.B.6.c **Condition:**

Total emissions of CO from all three turbines shall be no greater than 26.9 lbs/hour (15% $O_2$, dry) based on 8-hour block average under steady state operation (not including startup and shutdown). Emission of CO from each individual turbine shall be no greater than 10 ppmdv (15% $O_2$, dry) based on 8-hour block average under steady state operation (not including startup and shutdown). [Authority granted under R307- 401- 6(1) [BACT]; condition originated in DAQE-204-02]

II.B.6.c.1 **Monitoring:**

The emission of CO shall be monitored by continuous emission monitoring system (CEMS). The permittee shall calibrate, maintain, and operate a CEMS as required by R307-170 to determine compliance with CO concentration (ppmdv) and CO mass emission rate (lb/hr). The emission rate (lb/hr) shall be calculated by multiplying the CO concentration and the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation. The CO concentration shall be determined from data generated by the CEMS. The quality assurance requirements of R307-170, Continuous Emission Monitoring Systems Program shall be used to fulfill data quality assurance requirements.

II.B.6.c.2 **Recordkeeping:**

Results of CO monitoring shall be recorded and maintained as required in R307-170 and as described in Provision I.S.1 of this permit.

II.B.6.c.3 **Reporting:**

The permittee shall comply with the reporting provisions in R307-170-9 and all the reporting provisions contained in Section I of this permit. The quarterly reports required in R307-170-9 is considered prompt notification of permit deviations required in Provision I.S.2.c of this permit if all information required by Provision I.S.2.c is included in the report.

II.B.6.d **Condition:**

Visible emissions shall be no greater than 10 percent opacity from each turbine. [Authority granted under Utah SIP IX.H.2.a.B; condition originated in DAQE-204-02]

II.B.6.d.1 **Monitoring:**

In lieu of monitoring via visible emission observations, fuel usage shall be monitored to demonstrate that only pipeline-quality natural gas is used as fuel.

II.B.6.d.2 **Recordkeeping:**

Results of monitoring shall be maintained in accordance with Provision I.S.1 of this permit.

II.B.6.d.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.6.e **Condition:**

Combined 12- month rolling emissions from the three natural gas turbines shall not exceed 29.5 tons for $PM_{10}$, 81.0 tons for $NO_x$, 98.30 tons for CO, and 6.12 tons for $SO_2$. [Authority granted under R307- 401- 6(1) [BACT]; condition originated in DAQE-204-02]

II.B.6.e.1 **Monitoring:**

The emissions shall be determined on a rolling 12-month total. Within the first 10 days of each month, the total shall be calculated for each calendar month and added to the previous 11 months data.

Monthly emissions shall be the sum of emissions from each turbine and shall be calculated using the following equation:

Monthly emissions (tons) turbine heat input [MMBtu/month] x emission factor [lb/MMBtu) x (1 ton/2000 lbs)

Fuel consumption shall be determined by a fuel meter provided for each turbine or from CEMs data. Emission factors shall be as follows:

1. $PM_{10}$ shall be obtained from EPA's Compilation of Air Pollutant Emission Factors, AP-42 (Supplement F EPA, April 2000);

2. $NO_x$ monthly average emission factor in lb/MMBtu shall be calculated from CEM-recorded data (ppmdv) based on 40 CFR Part 60 App. A. Method 19;

3. CO monthly average emission factor in lb/MMBtu shall be calculated from CEM-recorded data (ppmdv) based on 40 CFR Part 60 App. A. Method 19;

4. $SO_2$ emission factor shall be calculated using natural gas sulfur content data (supplied by local gas distribution company) and the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (Supplement F EPA, April 2000)

II.B.6.e.2 **Recordkeeping:**

Records such as gas meter readings, or CEMs data shall be kept on a continuous basis. Records shall be maintained as described in Provision I.S of this permit.

II.B.6.e.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.B.6.f **Condition:**

Sulfur content of any fuel burned shall be no greater than 0.8 % by weight. [Authority granted under 40 CFR 60 Subpart GG; condition originated in DAQE-204-02]

II.B.6.f.1 **Monitoring:**

In lieu of monitoring the total sulfur content of gaseous fuel combusted in the turbines, the permittee should use one of the following sources of information to demonstrate that the gaseous fuel meets the definition of natural gas in 40 CFR 60.331(u):
(a) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or
(b) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.

II.B.6.f.2 **Recordkeeping:**

Results of monitoring shall be maintained in accordance with Provision I.S.1 of this permit.

II.B.6.f.3 **Reporting:**

There are no reporting requirements for this provision except those specified in Section I of this permit.

II.C. **Emissions Trading.**

(R307-415-6a(10))

Not applicable to this source.

II.D. **Alternative Operating Scenarios.**

(R307-415-6a(9))

Not applicable to this source.

II.E. **Source-specific Definitions.**

The following definitions apply to the permittee. They include terms not defined in state or federal rules or clarify or expand on existing definitions.

II.E.1 *Startup.* For Units#1, #2, and #3, startup begins when the forced draft and induced draft fans are turned on and when fuel is fed to the boiler with the intent to bring the unit on line to generate power and ends when the generating units reach minimum load. The minimum load is 20 MW for Unit 1, 25 MW for Unit #2, and 30 MW for Unit#3. For gas turbines, start up begins when natural gas is fed to the turbines with the intent of combusting fuel to generate electricity and ends when the SCR is placed into service.

II.E.2 *Shutdown.* For Units #1,#2, and #3, shutdown begins when the load is reduced with the intent of bringing the unit off line and ends when the fuel flow ends and the forced draft fans are turned off. For gas turbines, shutdown occurs at the cessation of natural gas flow to the combustion gas turbines.

II.E.3 *Downtime*. Downtime is that time between the end of shutdown and the beginning of startup.

II.E.4 *Maintenance Outage.* The removal of a unit from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

II.E.5 *Planned Outage.* The removal of a unit from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.

## Section III: PERMIT SHIELD

The following requirements have been determined to be not applicable to this source in accordance with Provision I.M, Permit Shield:

III.A. **40 CFR Part 60, Subpart D (Standards of Performance for New Stationary Sources for Fossil-Fuel-Fired Steam Generators)**

This regulation is not applicable to the Steam Generating Units (Emission unit # 4) because construction commenced prior to August 17, 1971

III.B. **40 CFR, Part 60, Subpart Da (NSPS for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)**

This regulation is not applicable to the Steam Generating Units (Emission unit # 4) because construction commenced prior to September 18, 1978

III.C. **40 CFR, Part 60, Subpart K (NSPS/ Volatile Organic Liquid Storage Vessels)**

This regulation is not applicable to the Distillate Fuel Oil Tank (Emission unit # 11) because this standard does not apply to Nos. 2 through 6 fuel oils or diesel fuels

III.D. **40 CFR, Part 60, Subpart Ka (NSPS/ Volatile Organic Liquid Storage Vessels)**

This regulation is not applicable to the Distillate Fuel Oil Tank (Emission unit # 11) because this standard does not apply to Nos. 2 through 6 fuel oils or diesel fuels

III.E. **40 CFR, Part 60, Subpart Kb (NSPS/ Volatile Organic Liquid Storage Vessels)**

This regulation is not applicable to the Distillate Fuel Oil Tank (Emission unit # 11) because construction commenced prior to July 23, 1984

III.F. **40 CFR, Part 60, Subpart Y (NSPS for Coal Preparation Plants)**

This regulation is not applicable to the permitted source (Source-wide) because natural gas is the primary fuel at this source and coal is not processed at this plant

III.G. **40 CFR, Part 60, Subpart OOO (Non-metallic mineral processing)**

This regulation is not applicable to the permitted source (Source-wide) because the process of crushing and grinding nonmetallic minerals is not performed at this source

III.H. **40 CFR, Part 63, Subpart Q (NESHAP for Industrial Process Cooling Towers)**

This regulation is not applicable to the Emission Unit #1 Cooling Towers (Emission unit # 7) because the cooling towers are not operated with chromium-based water treatment chemicals

III.I. **40 CFR, Part 63, Subpart Q (NESHAP for Industrial Process Cooling Towers)**

This regulation is not applicable to the Emission Unit #2 Cooling Towers (Emission unit # 8) because the cooling towers are not operated with chromium-based water treatment chemicals

III.J. **40 CFR, Part 63, Subpart Q (NESHAP for Industrial Process Cooling Towers)**

This regulation is not applicable to the Emission Unit #3 Cooling Towers (Emission unit # 9) because the cooling towers are not operated with chromium-based water treatment chemicals

## Section IV: ACID RAIN PROVISIONS.

IV.A. **Utah Acid Rain Program Authority.**

Authority to implement the Acid Rain Program is contained in R307-417, *Permits: Acid Rain Sources*, and R307-415-6a(4), *Standard permit requirements* [for operating permits].

IV.B. **Permit Requirements.**

IV.B.1 The designated representative of the source and each affected unit at the source shall:

IV.B.1.a Submit a complete Acid Rain permit application (including a compliance plan) under R307-417 and 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

IV.B.1.b Submit in a timely manner any supplemental information that the Executive Secretary determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

IV.B.2 The owners and operators shall:

IV.B.2.a Operate each affected unit at the source in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Executive Secretary; and

IV.B.2.b Have an Acid Rain Permit.

IV.C. **Sulfur Dioxide Requirements.**

IV.C.1 The owners and operators of each affected unit at the source shall:

IV.C.1.a Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

IV.C.1.b Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

IV.C.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

IV.C.3 An affected unit shall be subject to the requirements under Provision IV.C.1. of the sulfur dioxide requirements as follows:

IV.C.3.a Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

IV.C.3.b Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR 72.6(a)(3).

IV.C.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

IV.C.5 An allowance shall not be deducted in order to comply with the requirements under Provision IV.C.1.a. of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

IV.C.6 An allowance allocated by the Administrator, USEPA, under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

IV.C.7 An allowance allocated by the Administrator, USEPA, under the Acid Rain Program does not constitute a property right.

IV.D. **Nitrogen Oxides Requirements.**

The owner and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxide.

IV.E. **Monitoring Requirements.**

IV.E.1 The owners and operators and, to the extent applicable, designated representative of each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Parts 74, 75, and 76.

IV.E.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

IV.E.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

IV.F. **Recordkeeping and Reporting Requirements.**

IV.F.1 Unless otherwise provided, the owners and operators for each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator, USEPA, or Executive Secretary:

IV.F.1.a The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

IV.F.1.b All emissions monitoring information, in accordance with 40 CFR Part 75;

IV.F.1.c Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

IV.F.1.d Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

IV.F.2 The designated representative of each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72 Subpart I and 40 CFR Part 75.

IV.G. **Excess Emissions Requirements.**

IV.G.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator, USEPA, as required under 40 CFR Part 77.

IV.G.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

IV.G.2.a Pay without demand the penalty required, and pay upon demand the interest on that penalty, to the Administrator, USEPA, as required by 40 CFR Part 77; and

IV.G.2.b Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

IV.H. **Liability.**

IV.H.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under R307-417, 40 CFR 72.7 or 40 CFR 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

IV.H.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

IV.H.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

IV.H.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

IV.H.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

IV.H.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 ($NO_x$ averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not the owners and operators, owners or operators, or the designated representative.

IV.H.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

IV.H.8 The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

IV.I. **Effect on Other Authorities.**

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

IV.I.1 Except as expressly provided in Title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative from compliance with any other provision of the Act, including the provisions of Title I of the Act relating to applicable National Ambient Air Quality Standards or the Utah State Implementation Plan;

IV.I.2 Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;

IV.I.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

IV.I.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

IV.I.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

# REVIEWER COMMENTS

This operating permit incorporates all applicable requirements contained in the following documents:

DAQE-204-02 dated April 03, 2002

1. **Comment on an item originating in 40 CFR Part 72, 73, 75, 76, 77 and 78 regarding permitted source (Source-wide)**
   Acid Rain Program Affected Units: Steam Generating Units #1, #2, #3 and three natural gas simple cycle turbines (emission unit #24) are affected units under the Acid Rain Program as set forth in 40 CFR Parts 72, 73, 75, 77, and 78. The Acid Rain Boiler ID #'s are 1, 2, 3, 4, 5, and 6, respectively. Acid Rain requirements are contained in Section IV of the permit. All requirements of Section IV are enforceable upon the issue date of the permit unless otherwise specified in the condition (e.g. some $SO_2$ requirements). [Comment last updated on 6/29/2004]

2. **Comment on an item originating in DAQE-204-02 regarding Steam Generating Units (Unit 4)**
   Periodic Monitoring, Recordkeeping, and Reporting for SIP and AO $NO_x$ Limits: Emission units 1, 2 and 3 are Acid Rain Program affected units and are required to install a continuous emission monitor system (CEMS) for $NO_x$ (40 CFR Part 75). Emission unit 3 is also subject to 40 CFR Part 51, Appendix P and therefore, R307-170 applies to this unit. Part 75 CEM monitor and associated quality control and quality assurance programs are required to demonstrate compliance with the $NO_x$ emission limits. R307-170 requirements in addition to Part 75 are required for the emission unit 3. [Comment last updated on 6/09/2004]

3. **Comment on an item originating in DAQE-204-02 regarding Steam Generating Units (Unit 4)**
   Periodic Monitoring of $NO_x$ Emission Rate: Acid rain CEMS are required by the permit to determine the compliance with the $NO_x$ emission limits (lb/hr) in lieu of the Reference Method stack test from the underlying AO. Acid rain CEMS can provide reasonable assurance of compliance on a continuous basis. In addition, acid rain CEMS are required to conduct Relative Accuracy Test Audit (RATA) semiannually or at least annually. During RATA tests, the reference methods (stack test) are conducted. Therefore, the AO requirement for a stack test once every two years is redundant with the requirement for acid rain CEMS and can be considered to have been subsumed by the requirement for acid rain CEMS, for purposes of $NO_x$ emission monitoring in lb/hr. [Comment last updated on 4/09/2002]

4. **Comment on an item originating in DAQE-204-02 regarding Steam Generating Units (Unit 4)**
   Determination of $NO_x$ emission: The average time periods for $NO_x$ limits are not defined in the AO. All three units are not subject to NSPS. Method 7 is required in the

AO. Therefore, arithmetic average of three contiguous one-hour periods from Method 7 is used to demonstrate compliance with the limits.

All three units are the affected units of the Acid Rain Program and are required to install the $NO_x$ CEMS and $O_2$ or $CO_2$ CEMS. Gadsby chose to install the $CO_2$ CEMS. The hourly average $NO_x$ emission rate (lb/MMBtu) is determined by the $NO_x$ concentration (in ppm) and diluent concentration (in percent $CO_2$) measurements according to the procedures in appendix F of Part 75.

The Title V operating permit has $NO_x$ emission limits in the mass rate (lb/hr). The source proposed to calculate the mass rate using CEMS data. The mass emission rate (lb/hr) is calculated by multiplying the $NO_x$ emission rate (lb/MMBtu) by the hourly average heat input (MMBtu/hr). The hourly average heat input shall be calculated by multiplying the measured fuel flow rate (scf/hr) by the hourly average $CO_2$ concentration and by any necessary conversion factors according to the procedures in Appendix F of 40 CFR Part 75.

The Title V operating permit also has $NO_x$ concentration limits based on 3% $O_2$. For a given fuel, $O_2$ concentration can be determined from $CO_2$ concentration according to the procedures in Appendix F of 40 CFR Part 75. The $NO_x$ concentration should be corrected to 3% $O_2$ by using data generated from $NO_x$ and $CO_2$ CEMS. [Comment last updated on 7/14/2004]

**5. Comment on an item originating in DAQE-204-02 regarding Steam Generating Units (Unit 4)**

Maintenance Firings: Condition II.B.5.B requires that maintenance firing not exceed one-percent of the annual plant heat input requirement. The annual plant heat input requirement is not defined in the AO. Since there are no fuel consumption or production limitations in the AO, the annual plant BTU requirements can be up to the sum of the maximum capacity of boilers (726+825+1155) MMBtu x 8760 hrs=2706 MMBtu/hr x 8760 hr). Therefore, the percentage of the heat input during maintenance firings can be calculated as follow:

The percent of the heat input during maintenance firing = (Sum of the heat input (MMBtu) of all three boilers during maintenance firings of a calendar year)/ (2706 MMBtu/hrx8760 hrs) x 100 [Comment last updated on 4/09/2002]

**6. Comment on an item originating in DAQE-204-02 regarding Steam Generating Units (Unit 4)**

Electrostatic Precipitators: An electrostatic precipitator was installed for Steam Generating Unit #2 and #3, respectively. The electrostatic precipitators are not in service now because the generating units are only permitted to use natural gas. [Comment last updated on 4/09/2002]

**7. Comment on an item originating in this permit regarding Water Treatment Chemical Tanks (Unit 16)**

Water Treatment Chemical Tanks: Gadsby has tanks to store chemicals to treat water. The chemicals stored include sulfuric acid, corrosion inhibitor, sodium hypochlorite, aluminum sulfate, vertan 675 and hydrazine (35%). 40 CFR Part 68 (Chemical Accident Prevention Provisions) is not applicable to these tanks. [Comment last updated on 10/28/1998]

8. **Comment on an item originating in DAQE-204-02 regarding permitted source (Source-wide)**

Separate Control of Large Petroleum Storage Tanks: Five large petroleum storage tanks and one fuel tank located in the northwest corner of the Gadsby site property are not included in this source. There is one 1,764,000 gallon tank, four 882,000 gallon tanks, and one 14,800 gallon fuel tank. The tanks are owned by Pacificorp, but are leased to Petro Source Corporation who uses the tanks to store and transfer asphalt products (SIC 29XX). Petro Source has been issued the approval order to operate the tank farm. Therefore, the tanks are not part of the Gadsby Plant source for purposes of NSR or Title V based on the fact that there is no "common control" and there are different two-digit SIC codes. [Comment last updated on 4/09/2002]

9. **Comment on an item originating in 40 CFR Subpar GG regarding Natural Gas Simple Cycle Turbines Units (Unit 24)**

Alternative Monitoring for NSPS GG: EPA letter from Martin Hestmark dated on July 19, 2002 approved following alternative monitoring (based on the CEM used to monitor $NO_x$ emission will be spanned sufficiently to produce valid $NO_x$ data for demonstrating compliance both state BACT limit (5 ppmdv) and the NSPS GG limit of 116 ppmdv at 15% oxygen content at ISO condition).
1) Waive nitrogen monitoring (40 CFR 60.334(b)(2));
2) Method 7e, instead of method 20 (40 CFR 60.335 (c)(3)) can be used for initial performance test;
3) In lieu of daily monitoring, bimonthly sulfur monitoring for six months, then switch to quarterly monitoring if the data collected demonstrates little variability in sulfur content and compliance with the Subpart GG standard for sulfur dioxide.
EPA letter from Martin Hestmark dated on Aug. 29, 2002 approved following alternative monitoring:
1) Waive the water-to-fuel ratio monitoring (40 CFR 60.334(a)); [Comment last updated on 10/17/2002]

10. **Comment on an item originating in DAQE-204-02 regarding Natural Gas Simple Cycle Turbines Units (Unit 24)**

CEM Plan: condition 17 of AO requires the permittee submit for review and Executive Secretary approval CEMs monitoring plan 45 days before the turbine becomes operational. This is one time requirement and the permittee has already submitted the plan. Therefore, this condition is not carried into this permit. [Comment last updated on 1/29/2003]

11. **Comment on an item originating in this permit regarding permitted source (Source-wide)**

Renewal Permit: 1) $NO_x$ monitoring for Steam Generating Units: In the original permit, the permittee was not required to demonstrate compliance continuously with $NO_x$ ppmdv limits (3% $O_2$ dry). The $NO_x$ concentrations ppmdv were corrected to 3% $O_2$ dry only during the RATA tests. In the renewal permit, the permittee is required to demonstrate compliance continuously with $NO_x$ ppmdv (3%$O_2$ dry) limits with the existing $NO_x$ and $CO_2$ CEMS;
2) The requirement of initial $NO_x$ compliance stack testing for natural gas turbines is removed in the renewal permit. The permittee had fulfilled the initial stack testing requirement;

3) 40 CFR Part 75 requirements are removed from natural gas turbines (EU#24) CO monitoring, recordkeeping, and reporting (MRR). Because CO monitoring is not regulated by 40 CFR Part 75.
4) Amendments to NSPS Subpart GG (7/8/2004) are included in the renewal permit as follow:
a) Sulfur nitrogen monitoring is not required for natural gas turbines (EU#240, since the turbines only combust natural gas;
b) For excess emission report required under subpart GG, the averaging time period is increased from one hour to 4 four. [Comment last updated on 8/20/2004]